Docket:	:	A.13-12-012
Exhibit Number	:	ORA-04D
Commissioner	:	C. Peterman
ALJ	:	J. Wong
Witness	:	D. Phan

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Report on the Results of Operations for Pacific Gas and Electric Company Test Year 2015 Gas Transmission and Storage Rate Case

Chapter 4
Transmission Pipe Integrity and Emergency Response Programs: Direct Assessment

WORKPAPERS

San Francisco, California
August 19, 2014

Table of Content

U.S. Department of Transportation Pipeline & Hazardous Materials Safety Administration

Pipeline Safety Stakeholder Communications

Pipeline Safety Connects Us All

Fact Sheet: Direct Assessment (DA) - Gas Pipelines

Quick Facts:

- *Direct Assessment is identified in the Gas Pipeline Integrity Management Rule as one of the three acceptable methods for evaluating the integrity of a pipeline segment.*
- *Direct Assessment may be used either as a primary or a supplementary method, implemented in conjunction with one of the other primary assessment methods, i.e. inline inspection (ILI) or hydrostatic pressure testing.*
- *Direct Assessment — also known as DA — is limited to evaluating the risks of three time-dependent threats to the integrity of a pipeline segment: external corrosion, internal corrosion, and stress corrosion cracking.*
- *The Gas Pipeline Integrity Management Rule — also known as the "gas IM rule" — contained in Subpart O of 49 CFR Part 192 provides for specific and separate requirements for applying DA for external corrosion (ECDA) (§192.925), internal corrosion (ICDA) (§192.927), and stress corrosion cracking (SCCDA) (§192.929).*
- *When a pipeline segment is scheduled for a full integrity reassessment at an interval longer than 7 years, confirmatory direct assessment (CDA) (§192.931) may be used during the seventh year following a baseline assessment to verify or "confirm" the integrity of a pipeline from external and internal corrosion threats only.*
- *The Gas Pipeline Integrity Management Rule contains more restrictive requirements for operators applying DA for the first time on a pipeline segment.*
- *If external corrosion direct assessment (ECDA) finds pipeline coating damage, the operator must integrate the data from ECDA with one-call notification information and right-of-way information to evaluate the segment for the threat of third-party damage.*

Why do pipeline operators use direct assessment to evaluate the integrity of a pipeline?

DA is needed as an integrity assessment method for pipeline segments:

- Where ILI or hydrostatic pressure testing cannot be used,
- To avoid impractical, costly retrofitting of a pipeline,

(1)

- To avoid interrupting gas supply to a community fed by a single pipeline, and,
- To provide an alternative where sources of water for hydrostatic pressure testing are scarce, and where water disposal may create problems.
- DA may provide a more effective, equivalent alternative to ILI and hydrostatic pressure testing for evaluating a pipeline's integrity.

How is direct assessment carried out?

The gas IM rule specifies a four-step approach for evaluating corrosion threats using DA. For external corrosion direct assessment (ECDA), the gas IM rule requires:

Step One: Pre-assessment - to gather and integrate data to determine the feasibility of using ECDA for a segment, the identification of ECDA regions, and the identification of two indirect examination tools to be used on the ECDA region.

Step Two: Indirect Examination - to evaluate the pipe segment and identify indications of potential external corrosion, to classify the severity of those indications, and determine urgency for their excavation and direct examination.

Step Three: Direct Examination - to examine the condition of the pipe and its environment, to determine actions to be taken should corrosion defects be found, and to identify and address root causes.

Step Four: Post Assessment - to determine a segment's remaining life, its re-assessment interval, and the effectiveness of using ECDA as an assessment method.

For internal corrosion direct assessment (ICDA), the gas IM rule also specifies a four-step process, based on the principle that liquids collect on the bottom of a pipe when a "critical angle of inclination" is exceeded for a specific gas flow velocity. (§192.927):

Step One: Pre-assessment - to gather and integrate data and information to determine whether ICDA is feasible for the segment, to support use of a model to identify locations where liquids may accumulate, and to identify where liquids may enter the pipeline.

Step Two: CDA region identification - to apply a specific model to identify elevation conditions and other pipeline fittings where liquids may accumulate.

Step Three: Direct Examination - to excavate and examine pipe locations identified by the process as most likely for internal corrosion, and to evaluate the severity of defects and remediate as code requires.

Step Four: Post assessment evaluation and monitoring - to evaluate the effectiveness of the ICDA process, to monitor segments where internal corrosion was identified, and to determine re-assessment intervals.

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Stress corrosion cracking direct assessment (SCCDA) requires a plan that provides for:

1. **Data gathering and integration** — to determine whether the conditions for stress corrosion cracking are present, requiring an assessment for SCC; to prioritize pipeline segments for assessment; and to gather and evaluate data related to stress corrosion cracking at all operator excavation sites. When all of the following conditions for high pH SCC are present — operating stress greater than 60% of SMYS; operating temperature greater than 100°F; within 20 miles downstream of a compressor station; age greater than 10 years; and pipe coating other than fusion bonded epoxy — an assessment method must be applied.
2. **Assessment method** — to evaluate segments for the presence of stress corrosion cracking; determine its severity and prevalence; repair, remove or hydrostatically test the valve section; and determine any further mitigation requirements.

Should conditions for SCC be present in a segment, the segment must be assessed and remediated, as specified in Appendix A3 of ASME B31.8S, applying:

- The bell hole examination and evaluation method, or
- The hydrostatic pressure testing method for SCC.

Applying CDA requires a plan specifying that CDA can only be used on internal and external corrosion threats (§192.931).

1. For external corrosion (EC), the plan must comply with §192.925, however:
   - Only one indirect examination tool may be used, and one high risk indication examined in each ECDA region; and
   - All immediate indications must be excavated in each ECDA region.

2. For internal corrosion (IC), an operator's plan must comply with §192.927, however: only one high risk location must be excavated in each ICDA region.
3. When applying either ICDA or ECDA, if defects are found requiring remediation before the next scheduled assessment, the operator is required to apply the formula in § 6.2 and 6.3 of the National Association of Corrosion Engineers (NACE) Recommended Practice 0502 to schedule the next assessment.

Are standards being developed for ICDA and SCCDA?

In December, 2004, NACE adopted Recommended Practice 0204 for Stress Corrosion Cracking Direct Assessment (SCCDA), and is now in the process of adopting a proposed recommended practice for Internal Corrosion Direct Assessment. These will provide operators additional guidance for addressing threats.

Are there referenced standards which must be met when applying DA?

- For ECDA: NACE RP 0502-2002, and ASME B31.8S §6.4.

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- For ICDA and for SCCDA: ASME B31.8S § 6.4, Appendices A2, B2 & A3.
- For ICDA: Gas Technology Institute, GRI-02-0057, "Internal Corrosion Direct Assessment of Gas Transmission Lines - Methodology".

Date of Revision: 12012011

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locations near the pipeline meeting these criteria. If no public officials have such knowledge, then the operator must identify facilities that either: have visible signs; are licensed by a Federal, State, or local government agency; or appear on a list or map available from such an agency. See OPS's Advisory Bulletin ADB-03-03 dated July 17, 2003, (available on this web site -- http://primis.phmsa.dot.gov/gasimp under "key documents") for additional guidance.

FAQ-19. What are OPS expectations for operators to determine new or changed HCAs? [05/17/2004]

Operators must continually monitor conditions along their pipeline. When they become aware of population or usage changes that create or change an HCA (e.g., population expands to encompass more of the area near the pipeline right-of-way), this information should be factored, at least once per calendar year, into their integrity assessment planning, risk analysis, and consideration of the need for additional preventive and mitigative risk controls.

FAQ-20. When must newly-identified HCAs be included in the program? [08/17/2004]

Over time, new HCAs may be identified, such as when population distributions change or new sites that are occupied by 20 or more persons are identified. Operators must consider such changes to determine whether new HCAs have been created. A newly-identified HCA must be incorporated into the integrity management program (including the baseline assessment plan) within one year of its identification. A baseline assessment for pipeline segments in newly identified HCAs must be performed within ten years of its identification.

FAQ-21. Must non-pipe elements of a pipeline system in HCAs (e.g., compressor stations) be identified by 12/17/04? [05/17/2004]

Yes. While the assessment requirements of 49 CFR 192 Subpart O are applicable to line pipe, all other requirements, including covered segment identification, are applicable to the entire pipeline, which is defined in 49 CFR 192.3 as all parts of those physical facilities through which gas moves in transportation. OPS expects operators to understand which compressor stations and other facilities meet criteria to be treated as covered segments in HCAs.

FAQ-22. Why is it important that operators know the specific characteristics of high consequence areas their pipelines traverse? [08/14/2006]

Operators need to know the characteristics of HCAs along their pipeline to make decisions required by the integrity management rule. For example, the number/nature of housing units (e.g., large apartment buildings) can affect the consequences of a leak or rupture, and thus affect the relative risk ranking of a segment or decisions regarding preventive and mitigative measures. Section 3.3 of ASME/ANSI B31.8S specifies additional consequence factors to consider, including security of gas supply, public convenience and necessity, and the potential for secondary failures.

FAQ-117. How often must an operator update its building density survey and list of identified sites to determine if new HCAs have been created? [06/09/2004]

The rule does not specify a frequency for updating data used to identify HCAs. Instead, the rule states that operators must complete an evaluation when they have information that the area around a segment not previously identified as an HCA has changed so that it might now be one. Operators are expected to assure that their HCA definitions are current. In an area in which there

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U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration	ANNUAL REPORT FOR CALENDAR YEAR 2011 NATURAL OR OTHER GAS TRANSMISSION and GATHERING SYSTEMS	Report Submission Type INITIAL

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 22 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

Important: Please read the separate instructions for completing this form before you begin.

PART A - OPERATOR INFORMATION	DOT USE ONLY	20120944 - 25538

1. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER (OPID)

15007

2. NAME OF COMPANY OR ESTABLISHMENT:

PACIFIC GAS & ELECTRIC CO

IF SUBSIDIARY, NAME OF PARENT:

PG&E Corporation

3. INDIVIDUAL WHERE ADDITIONAL INFORMATION MAY BE OBTAINED:

Name: **Laurence Deniston**

Title: **Sr. Program Manager**

Email Address: **lcd1@pge.com**

Telephone Number: **(925) 974-4313**

4. HEADQUARTERS ADDRESS:

Pacific Gas & Electric Co.
Company Name

77 Beale Street, San Francisco
Street Address

State: **CA** Zip Code: **94105**

(800) 743-5000
Telephone Number

5. THIS REPORT PERTAINS TO THE FOLLOWING COMMODITY GROUP: *(Select Commodity Group based on the predominant gas carried and complete the report for that Commodity Group. File a separate report for each Commodity Group included in this OPID.)*

Natural Gas

6. CHARACTERIZE THE PIPELINES AND/OR PIPELINE FACILITIES COVERED BY THIS OPID AND COMMODITY GROUP WITH RESPECT TO COMPLIANCE WITH PHMSA'S INTEGRITY MANAGEMENT PROGRAM REGULATIONS (49 CFR 192 Subpart O).

Portions of SOME OR ALL of the pipelines and/or pipeline facilities covered by this OPID and Commodity Group are included in an Integrity Management Program subject to 49 CFR 192. If this box is checked, complete all PARTs of this form in accordance with PART A, Question 8.

7. FOR THE DESIGNATED "COMMODITY GROUP", THE PIPELINES AND/OR PIPELINE FACILITIES INCLUDED WITHIN THIS OPID ARE: *(Select one or both)*

INTERstate pipeline - List all of the States in which INTERstate pipelines and/or pipeline facilities included under this OPID exist: etc.

INTRAstate pipeline - List all of the States in which INTRAstate pipelines and/or pipeline facilities included under this OPID exist: **CALIFORNIA** etc.

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8. DOES THIS REPORT REPRESENT A CHANGE FROM LAST YEAR'S FINAL REPORTED NUMBERS FOR ONE OR MORE OF THE FOLLOWING PARTs: PART B, D, E, H, I, J, K, or L? *(For calendar year 2010 reporting or if this is a first-time Report for an operator or OPID, Commodity Group(s), or pipelines and/or pipeline facilities, select the first box only. For subsequent years' reporting, select either No or one or both of the Yes choices.)*

☐ This report is **FOR CALENDAR YEAR 2010** reporting **or is a FIRST-TIME REPORT** and, therefore, *the remaining choices in this Question 8 do not apply.* Complete all remaining PARTS of this form as applicable

☐ NO, there are **NO CHANGES** from last year's final reported information for PARTs B, D, E, H, I, J, K, or L. Complete PARTs A, C, M, and N, along with PARTs F, G, and O when applicable.

☐ YES, this report represents a **CHANGE FROM LAST YEAR'S FINAL REPORTED INFORMATION** for one or more of PARTs B, D, E, H, I, J, K, or L ***due to corrected information****; however, the pipelines and/or pipeline facilities and operations are the same* as those which were covered under last year's report. Complete PARTs A, C, M, and N, along with only those other PARTs which changed (including PARTs B, F, G, and O when applicable).

☑ YES, this report represents a **CHANGE FROM LAST YEAR'S FINAL REPORTED INFORMATION** for PARTs B, D, E, H, I, J, K, or L because of one or more of the following ***change(s) in pipelines and/or pipeline facilities and/or operations*** from those which were covered under last year's report. Complete PARTs A, C, M, and N, along with only those other PARTs which changed (including PARTs B, F, G, and O when applicable). *(Select all reasons for these changes from the following list)*

- ☐ Merger of companies and/or operations, acquisition of pipelines and/or pipeline facilities
- ☐ Divestiture of pipelines and/or pipeline facilities
- ☑ New construction or new installation of pipelines and/or pipeline facilities
- ☐ Conversion to service, change in commodity transported, or c change in MAOP (maximum allowable operating pressure)
- ☐ Abandonment of existing pipelines and/or pipeline facilities
- ☑ Change in HCA's identified, HCA Segments, or other changes to Operator's Integrity Management Program
- ☐ Change in OPID

Other – Describe: , false

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For the designated Commodity Group, complete PARTs B, C, D, and E one time for all pipelines and/or pipeline facilities – both INTERstate and INTRAstate - included within this OPID.

PART B – TRANSMISSION PIPELINE HCA MILES	
	Number of HCA Miles in the IMP Program
Onshore	1040
Offshore	0
Total Miles	1040

1,040 mile.

PART C - VOLUME TRANSPORTED IN TRANSMISSION PIPELINES (ONLY) IN MILLION SCF PER YEAR (excludesTransmission lines of Gas Distribution systems)	Check this box and proceed to PART D without completing this PART C if this report only includes gathering pipelines or transmission lines of gas distribution systems.	
	Onshore	**Offshore**
Natural Gas	744415	
Propane Gas	0	
Synthetic Gas	0	
Hydrogen Gas	0	
Other Gas - Name: N	0	

PART D - MILES OF STEEL PIPE BY CORROSION PROTECTION					
	Cathodically protected		Cathodically unprotected		Total Miles
	Bare	Coated	Bare	Coated	
Transmission					
Onshore	8.7	5734.3	0	0	5743
Offshore	0	0	0	0	0
Subtotal Transmission	8.7	5734.3	0	0	5743
Gathering					
Onshore Type A	0	4.5	0	0	4.5
Onshore Type B	0	0	0	0	0
Offshore	0	0	0	0	0
Subtotal Gathering	0	4.5	0	0	4.5
Total Miles	8.7	5738.8	0	0	5747.5

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PART E - MILES OF non-STEEL PIPE BY TYPE AND LOCATION					
	Cast Iron Pipe	Wrought Iron Pipe	Plastic Pipe	Other Pipe	Total Miles
Transmission					
Onshore	0	.8	0	0	.8
Offshore	0	0	0	0	0
Subtotal Transmission	0	.8	0	0	.8
Gathering					
Onshore Type A	0	0	0	0	0
Onshore Type B	0	0	0	0	0
Offshore	0	0	0	0	0
Subtotal Gathering	0	0	0	0	0
Total Miles	0	.8	0	0	.8

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For the designated Commodity Group, complete PARTs F and G <u>one time for all INTERstate pipelines and/or pipeline facilities</u> included within this OPID and multiple times as needed for the designated Commodity Group <u>for each State in which INTRAstate pipelines and/or pipeline facilities</u> included within this OPID exist. Each time these sections are completed, designate the State to which the data applies for INTRAstate pipelines and/or pipeline facilities, or that it applies to all INTERstate pipelines included within this Commodity Group and OPID.

PARTs F and G
The data reported in these PARTs F and G applies to: *(select only one)*

PART F - INTEGRITY INSPECTIONS CONDUCTED AND ACTIONS TAKEN BASED ON INSPECTION INTRASTATE pipelines/pipeline facilities CALIFORNIA	
1. MILEAGE INSPECTED IN CALENDAR YEAR USING THE FOLLOWING IN-LINE INSPECTION (ILI) TOOLS	
a. Corrosion or metal loss tools	147
b. Dent or deformation tools	147
c. Crack or long seam defect detection tools	11.4
d. Any other internal inspection tools	0
e. Total tool mileage inspected in calendar year using in-line inspection tools. (Lines a + b + c + d)	305.4
2. ACTIONS TAKEN IN CALENDAR YEAR BASED ON IN-LINE INSPECTIONS	
a. Based on ILI data, total number of anomalies excavated in calendar year because they met the operator's criteria for excavation.	40
b. Total number of anomalies repaired in calendar year that were identified by ILI based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment.	27
c. Total number of conditions repaired WITHIN AN HCA SEGMENT meeting the definition of:	1
1. "Immediate repair conditions" [192.933(d)(1)]	1
2. "One-year conditions" [192.933(d)(2)]	0
3. "Monitored conditions" [192.933(d)(3)]	0
4. Other "Scheduled conditions" [192.933(c)]	0
3. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON PRESSURE TESTING	
a. Total mileage inspected by pressure testing in calendar year.	0
b. Total number of pressure test failures (ruptures and leaks) repaired in calendar year, both within an HCA Segment and outside of an HCA Segment.	0
c. Total number of pressure test ruptures (complete failure of pipe wall) repaired in calendar year WITHIN AN HCA SEGMENT.	0
d. Total number of pressure test leaks (less than complete wall failure but including escape of test medium) repaired in calendar year WITHIN AN HCA SEGMENT.	0
4. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON DA (Direct Assessment methods)	
a. Total mileage inspected by each DA method in calendar year.	132.5
1. ECDA	126.6
2. ICDA	1.6
3. SCCDA	4.3
b. Total number of anomalies identified by each DA method and repaired in calendar year based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment.	3
1. ECDA	3
2. ICDA	0
3. SCCDA	0
c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT meeting the definition of:	3
1. "Immediate repair conditions" [192.933(d)(1)]	1
2. "One-year conditions" [192.933(d)(2)]	0

3. "Monitored conditions" [192.933(d)(3)]	2
4. Other "Scheduled conditions" [192.933(c)]	0
5. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON OTHER INSPECTION TECHNIQUES	
a. Total mileage inspected by inspection techniques other than those listed above in calendar year.	0
b. Total number of anomalies identified by other inspection techniques and repaired in calendar year based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment.	0
c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT meeting the definition of:	0
1. "Immediate repair conditions" [192.933(d)(1)]	0
2. "One-year conditions" [192.933(d)(2)]	0
3. "Monitored conditions" [192.933(d)(3)]	0
4. Other "Scheduled conditions" [192.933(c)]	0
6. TOTAL MILEAGE INSPECTED (ALL METHODS) AND ACTIONS TAKEN IN CALENDAR YEAR	
a. Total mileage inspected in calendar year. (Lines 1.e + 3.a + 4.a.1 + 4.a.2 + 4.a.3 + 5.a)	437.9
b. Total number of anomalies repaired in calendar year both within an HCA Segment and outside of an HCA Segment. (Lines 2.b + 3.b + 4.b.1 + 4.b.2 + 4.b.3 + 5.b)	30
c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT. (Lines 2.c.1 + 2.c.2 + 2.c.3 + 2.c.4 + 3.c + 3.d + 4.c.1 + 4.c.2 + 4.c.3 + 4.c.4 + 5.c.1 + 5.c.2 + 5.c.3 + 5.c.4)	4
PART G– MILES OF BASELINE ASSESSMENTS AND REASSESSMENTS COMPLETED IN CALENDAR YEAR (HCA Segment miles ONLY)	
a. Baseline assessment miles completed during the calendar year.	86.5
b. Reassessment miles completed during the calendar year.	72.1
c. Total assessment and reassessment miles completed during the calendar year.	158.6

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For the designated Commodity Group, complete PARTs H, I, J, K, L, and M covering INTERstate pipelines and/or pipeline facilities for each State in which INTERstate systems exist within this OPID and again covering INTRAstate pipelines and/or pipeline facilities for each State in which INTRAstate systems exist within this OPID.

PARTs H, I, J, K, L and M

The data reported in these PARTs H, I, J, K, L and M applies to:

INTRASTATE pipelines/pipeline facilities CALIFORNIA

PART H - MILES OF TRANSMISSION PIPE BY NOMINAL PIPE SIZE (NPS)

Onshore	NPS 4" or less	6"	8"	10"	12"	14"	16"	18"	20"
	378.5	443.4	596.8	404.6	764.7	.1	385.3	59.9	223.4
	22"	24"	26"	28"	30"	32"	34"	36"	38"
	65.4	309.3	138.9	0	108.4	19	1023.8	521	0
	40"	42"	44"	46"	48"	50"	52"	54"	56"
	0	301.3	0	0	0	0	0	0	0
	58" and over	Additional Sizes and Miles (Size – Miles;): 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0;							
	0								
5743.8	Total Miles of Onshore Pipe – Transmission								
Offshore	NPS 4" or less	6"	8"	10"	12"	14"	16"	18"	20"
	22"	24"	26"	28"	30"	32"	34"	36"	38"
	40"	42"	44"	46"	48"	50"	52"	54"	56"
	58" and over	Additional Sizes and Miles (Size – Miles;): -; -; -; -; -; -; -; -; -;							
	Total Miles of Offshore Pipe – Transmission								

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PART I - MILES OF GATHERING PIPE BY NOMINAL PIPE SIZE (NPS)

Onshore Type A

NPS 4" or less	6"	8"	10"	12"	14"	16"	18"	20"
4.1	.4	0	0	0	0	0	0	0
22"	**24"**	**26"**	**28"**	**30"**	**32"**	**34"**	**36"**	**38"**
0	0	0	0	0	0	0	0	0

40"	42"	44"	46"	48"	50"	52"	54"	56"	58" and over
0	0	0	0	0	0	0	0	0	0

Additional Sizes and Miles (Size – Miles;): 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0;

4.5 Total Miles of Onshore Type A Pipe – Gathering

Onshore Type B

NPS 4" or less	6"	8"	10"	12"	14"	16"	18"	20"
0	0	0	0	0	0	0	0	0
22"	**24"**	**26"**	**28"**	**30"**	**32"**	**34"**	**36"**	**38"**
0	0	0	0	0	0	0	0	0

40"	42"	44"	46"	48"	50"	52"	54"	56"	58" and over
0	0	0	0	0	0	0	0	0	0

Additional Sizes and Miles (Size – Miles;): 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0;

0 Total Miles of Onshore Type B Pipe – Gathering

Offshore

NPS 4" or less	6"	8"	10"	12"	14"	16"	18"	20"
22"	**24"**	**26"**	**28"**	**30"**	**32"**	**34"**	**36"**	**38"**

40"	42"	44"	46"	48"	50"	52"	54"	56"	58" and over

Additional Sizes and Miles (Size – Miles;): -; -; -; -; -; -; -; -; -;

Total Miles of Offshore Pipe – Gathering

PART J – MILES OF PIPE BY DECADE INSTALLED

Decade Pipe Installed	Pre-40 or Unknown	1940 - 1949	1950 - 1959	1960 - 1969	1970 - 1979	1980 - 1989
Transmission						
Onshore	289.1	410.6	1960.6	1170.4	339.7	534.9
Offshore						
Subtotal Transmission	289.1	410.6	1960.6	1170.4	339.7	534.9
Gathering						
Onshore Type A	0	0	0	0	1.7	.8
Onshore Type B	0	0	0	0	0	0
Offshore						
Subtotal Gathering	0	0	0	0	1.7	.8

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Total Miles	289.1	410.6	1960.6	1170.4	341.4	535.7
Decade Pipe Installed	1990 - 1999	2000 - 2009	2010 - 2019			Total Miles
Transmission						
Onshore	784.2	208.8	45.5			5743.8
Offshore						
Subtotal Transmission	784.2	208.8	45.5			5743.8
Gathering						
Onshore Type A	2	0	0			4.5
Onshore Type B	0	0	0			0
Offshore						
Subtotal Gathering	2	0	0			4.5
Total Miles	786.2	208.8	45.5			5748.3

PART K- MILES OF TRANSMISSION PIPE BY SPECIFIED MINIMUM YIELD STRENGTH

ONSHORE	CLASS LOCATION				Total Miles
	Class I	Class 2	Class 3	Class 4	
Less than 20% SMYS	297.7	54.3	357.4	1.1	710.5
Greater than or equal to 20% SMYS but less than 30% SMYS	418.5	105.8	620.4	0	1144.7
Greater than or equal to 30% SMYS but less than or equal to 40% SMYS	334.6	77.1	350.7	.4	762.8
Greater than 40% SMYS but less than or equal to 50% SMYS	611.6	87.3	260.2	0	959.1
Greater than 50% SMYS but less than or equal to 60% SMYS	542.1	48.3	63.6	0	654
Greater than 60% SMYS but less than or equal to 72% SMYS	1480.2	31.7	0	0	1511.9
Greater than 72% SMYS but less than or equal to 80% SMYS	0	0	0	0	0
Greater than 80% SMYS	0	0	0	0	0
Unknown percent of SMYS	0	0	0	0	0
All Non-Steel pipe	0	0	.8	0	.8
Onshore Totals	3684.7	404.5	1653.1	1.5	5743.8
OFFSHORE	Class I				
Less than or equal to 50% SMYS					
Greater than 50% SMYS but less than or equal to 72% SMYS					
Offshore Total					
Total Miles	3684.7				5743.8

PART L - MILES OF PIPE BY CLASS LOCATION

	Class Location				Total Class Location Miles	HCA Miles in the IMP Program
	Class I	Class 2	Class 3	Class 4		

Transmission						
Onshore	3684.7	404.5	1653.1	1.5	5743.8	1040
Offshore	0	0	0	0	0	
Subtotal Transmission	3684.7	404.5	1653.1	1.5	5743.8	
Gathering						
Onshore Type A	0	4.5	0	0	4.5	
Onshore Type B	0	0	0	0	0	
Offshore	0	0	0	0	0	
Subtotal Gathering	0	4.5	0	0	4.5	
Total Miles	3684.7	409	1653.1	1.5	5748.3	1040

PART M – INCIDENTS, FAILURES, LEAKS, AND REPAIRS

PART M1 – ALL LEAKS ELIMINATED/REPAIRED IN CALENDAR YEAR; INCIDENTS & FAILURES IN HCA SEGMENTS IN CALENDAR YEAR

Cause	Transmission Incidents, Leaks, and Failures						Gathering Leaks		
	Incidents in HCA Segments	Leaks				Failures in HCA Segments	Onshore Leaks		Offshore Leaks
		Onshore Leaks		Offshore Leaks					
		HCA	Non-HCA	HCA	Non-HCA		Type A	Type B	
External Corrosion	0	1	5	0	0	0	0	0	0
Internal Corrosion	0	0	2	0	0	0	0	0	0
Stress Corrosion Cracking	0	0	0	0	0	0	0	0	0
Manufacturing	0	0	0	0	0	0	0	0	0
Construction	0	3	9	0	0	0	0	0	0
Equipment	0	4	20	0	0	3	0	0	0
Incorrect Operations	1	0	0	0	0	0	0	0	0
Third Party Damage/Mechanical Damage									
Excavation Damage	1	0	3	0	0	0	0	0	0
Previous Damage (due to Excavation Activity)	0	0	0	0	0	0	0	0	0
Vandalism (includes all Intentional Damage)	0	0	0	0	0	0	0	0	0
Weather Related/Other Outside Force									
Natural Force Damage (all)	0	0	0	0	0	0	0	0	0
Other Outside Force Damage (excluding Vandalism and all Intentional Damage)	0	0	0	0	0	0	0	0	0
Other	1	3	22	0	0	1	0	0	0
Total	3	11	61	0	0	4	0	0	0

PART M2 – KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR

Transmission	0	**Gathering**	0

PART M3 – LEAKS ON FEDERAL LAND OR OCS REPAIRED OR SCHEDULED FOR REPAIR

Transmission		**Gathering**	
Onshore	2	Onshore Type A	0
		Onshore Type B	0
OCS	0	OCS	0
Subtotal Transmission	2	Subtotal Gathering	0
Total	2		

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For the designated Commodity Group, complete PART N one time for all of the pipelines and/or pipeline facilities included within this OPID, and then also PART O if any portion(s) of the pipelines and/or pipeline facilities covered under this Commodity Group and OPID are included in an Integrity Management Program subject to 49 CFR 192.

PART N - PREPARER SIGNATURE (applicable to all PARTs A - M)

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PART O - CERTIFYING SIGNATURE (applicable only to PARTs B, F, G, and M1)

Nickolas Stavropolous
Senior Executive Officer's signature certifying the information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

(415) 973-2020
Telephone Number

Nickolas Stavropolous
Senior Executive Officer's name certifying the information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

Executive Vice President Gas Operations
Senior Executive Officer's title certifying the information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

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PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	ORA_014-02		
PG&E File Name:	GTS-RateCase2015_DR_ORA_014-Q02		
Request Date:	February 26, 2014	Requester DR No.:	ORA-GT&S-14
Date Sent:	March 10, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Sumeet Singh	Requester:	Nathaniel Skinner

SUBJECT: CHAPTER 4: ASSET FAMILY - TRANSMISSION PIPE

QUESTION 2

Provide information on transmission line segments that were required to be assessed under federal pipeline safety regulation 49 CFR Part 192, Subpart O or under D.12-12-030 and will not be completed by the end of 2014.

a) What transmission pipeline segments that require action / assessment will be complete by the end of 2014? Will any segments not be completed by the end of 2014? If so, please identify and explain.

b) How many total miles of transmission pipeline do the segments in part a) of question 2 cover?

c) What is the HCA mileage for the segments in part a) of question 2?

d) How are PSEP Replacement and Hydrostatic Testing Projects, not completed by the end of 2014, being tracked in this GT&S?

e) How are TIMP projects, not completed by the end of 2014, being tracked in this GT&S?

ANSWER 2

For the answer to this question, PG&E has broken apart the question to address Subpart O first, followed by a response to address D.12-12-030.

49 CFR Part 192 Subpart O

Annually, PG&E creates a Baseline Assessment Plan (BAP). The BAP is modified through threat analysis, analysis of changes in High Consequence Areas (HCAs), and risk analysis. Subpart O is, by definition, a risk based process to establish scheduling of integrity assessments within HCAs. PG&E uses the BAP to update integrity assessment and re-assessment intervals based on threat and risk analysis within HCAs.

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a. The last completed BAP (April 2013 for 2012 BAP), which shows required assessments under Subpart O, are provided as attachments GTS-RateCase2015_DR_ORA_014-Q02Atch01 (PG&E) and GTS-RateCase2015_DR_ORA_014-Q02Atch02 (StanPac). Integrity Assessments that are required to be completed by the end of 2014 are on schedule to be completed by the end of 2014.

b. The BAP includes 1,069 miles of HCA.

c. All miles in the BAP are HCA miles, as required by Subpart O. See the answer for part (b) above for the number of HCA miles.

d. This question does not apply to Subpart O. See below for the response to this subpart under the heading "D.12-12-030."

e. The BAP is modified annually through threat and risk analysis. PG&E is on track to complete those integrity assessments that are required to be completed in 2014 under Subpart O by the end of 2014. Therefore, there are no incomplete Transmission Integrity Management Program (TIMP) projects carrying into the 2015 GT&S Rate Case period.

D.12-12-030 (Pipeline Safety Enhancement Plan Phase 1)

a. See PG&E's Pipeline Safety Enhancement Plan (PSEP) Update Application (A.13-10-017) for the list of what is planned to be completed by the end of 2014 in accordance with D.12-12-030. All work that is planned for PSEP Phase 1, as shown in the PSEP Update Application, is currently on track to be completed by the end of 2014.

b. PSEP Phase 1 work that will be completed by the end of 2014 includes 658 miles of pipe that will be hydrostatically tested and 143 miles of pipe replacement.

c. The numbers of miles that are in HCAs are: 265 miles of hydrostatic testing and 47 miles of pipe replacement.

d. Those PSEP Phase 1 Hydrostatic Testing and Pipe Replacement projects that are planned for 2014 are expected to be completed by the end of 2014. In the Update Application, PG&E proposed to defer certain Hydrostatic Testing and Pipe Replacement miles identified in the August 2011 PSEP, until after 2014. These are captured in the 2015 GT&S Rate Case in the manner that is explained in the response to ORA_007-Q11.

e. This question does not apply to PSEP Phase 1. See above for the response to this subpart under the heading "49 CFR Part 192 Subpart O."

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PG&E Data Request No.:	ORA_070-03		
PG&E File Name:	GTS-RateCase2015_DR_ORA_070-Q03		
Request Date:	June 12, 2014	Requester DR No.:	ORA-GT&S-70
Date Sent:	June 26, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Bennie Barnes	Requester:	Dao Phan

SUBJECT: 2015 GAS TRANSMISSION AND STORAGE RATE CASE, PREPARED TESTIMONY, VOLUME 1 OF 2, CHAPTERS 4 AND 4A, PG&E'S REQUESTED EXPENSES FOR DIRECT ASSESSMENTS

QUESTION 3

Please identify the "total footage of piping scheduled to be assessed" as used under subsection f. "Forecast Methodology," on page 4A-31 of the testimony and provide a copy of all calculations, and/or documents used in development of this proposal.

ANSWER 3

The "total footage of piping scheduled to be assessed" refers to the forecasted number of miles to be assessed within the External Corrosion Direct Assessment (ECDA) program. The total footage of pipe for each program can be found in the workpapers supporting Chapter 4A on pages WP 4A-18, WP 4A-20 and WP 4A-22.

The ECDA program uses a combined approach of dig unit cost and survey unit cost to forecast the total cost of work required. As shown in workpapers on page WP 4A-18, the digs unit cost is based on a cost per dig while the survey unit cost is based on the cost per mile. Therefore, the ECDA part of the forecast stems from the calculation of the number of forecasted ECDA miles multiplied by the survey unit cost. However, the digs cost and the number of forecasted digs during the 2015 Gas Transmission and Storage (GT&S) Rate Case period needs to be included to provide a more accurate forecast.

Also, both the Internal Corrosion Direct Assessment (ICDA) and Stress Corrosion Cracking Direct Assessment (SCCDA) programs rely on a different type of unit cost than ECDA. ICDA relies on a unit cost per inspection site as shown in workpapers on page WP 4A-20. SCCDA relies on a unit cost per dig as shown in workpapers on page WP 4A-22. However, often while assessing for internal corrosion threat or stress corrosion cracking, PG&E assesses the pipeline for external corrosion. Therefore, it is still important to know the length of pipeline to be assessed in order to assess the pipeline using all three methods of direct assessment.

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PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
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Data Response

PG&E Data Request No.:	ORA_070-05		
PG&E File Name:	GTS-RateCase2015_DR_ORA_070-Q05		
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PG&E Witness:	Bennie Barnes	Requester:	Dao Phan

SUBJECT: 2015 GAS TRANSMISSION AND STORAGE RATE CASE, PREPARED TESTIMONY, VOLUME 1 OF 2, CHAPTERS 4 AND 4A, PG&E'S REQUESTED EXPENSES FOR DIRECT ASSESSMENTS

QUESTION 5

On page 4A-27, PG&E states, "the total mileage of pipeline that is scheduled to be assessed by ECDA for each year for the rate case period was determined by considering the assessment and reassessment due dates, ILI upgrades, and PSEP replacement schedules." Please provide a copy of any and all documents and calculations used to support this statement.

ANSWER 5

The attachment identified in this response has been marked CONFIDENTIAL and is submitted under Public Utilities Code Section 583 because it includes confidential employee information.

Please see Risk Management Procedure 06 (RMP-06), section 9 for the methodology and strategy used in creating integrity assessment schedules. Each segment of PG&E's transmission systems goes through a risk and threat analysis on an annual basis. The results of this analysis will include updates to existing High Consequence Area (HCA) boundaries, and determines the appropriate assessment tool for each HCA boundary.

For example, in 2008 through 2010 there were 392 miles of pipeline assessed using External Corrosion Direct Assessment (ECDA). The typical reassessment interval for segments assessed using ECDA is 7 years. This would suggest that from 2015 through 2017 the same 392 miles of pipeline would need to be reassessed under the ECDA program. As seen on workpaper page WP 4A-18, PG&E is only proposing to reassess 222 miles of pipeline from 2015 to 2017 using ECDA. As a result of the annual analysis described in RMP-06, it has been determined that approximately 170 miles of pipeline will be inspected using an alternative method or assessed earlier in the program.

Please see PG&E's response to Indicated Producers_002-Q085, attachment GTS-RateCase2015_DR_IndicatedProducers_002-Q085Atch03CONF for a copy of RMP-06.

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PG&E Data Request No.:	ORA_070-07		
PG&E File Name:	GTS-RateCase2015_DR_ORA_070-Q07		
Request Date:	June 12, 2014	Requester DR No.:	ORA-GT&S-70
Date Sent:	June 26, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Bennie Barnes	Requester:	Dao Phan

SUBJECT: **2015 GAS TRANSMISSION AND STORAGE RATE CASE, PREPARED TESTIMONY, VOLUME 1 OF 2, CHAPTERS 4 AND 4A, PG&E'S REQUESTED EXPENSES FOR DIRECT ASSESSMENTS**

QUESTION 7

Please explain whether or not PG&E's requests for ECDA, ICDA, and SCCDA expenses, as discussed in Chapter 4A are part of its Transmission Integrity Management Program.

ANSWER 7

Yes, External Corrosion Direct Assessment (ECDA), Internal Corrosion Direct Assessment (ICDA) and Stress Corrosion Cracking Direct Assessment (SCCDA) are part of PG&E's Transmission Integrity Management Program because the work focuses on High Consequence Area (HCA) assessments as required by 49 Code of Federal Regulations (CFR) 192, Subpart O.

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PACIFIC GAS AND ELECTRIC COMPANY
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Data Response

PG&E Data Request No.:	ORA_070-09		
PG&E File Name:	GTS-RateCase2015_DR_ORA_070-Q09		
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Date Sent:	June 26, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Bennie Barnes	Requester:	Dao Phan

SUBJECT: 2015 GAS TRANSMISSION AND STORAGE RATE CASE, PREPARED TESTIMONY, VOLUME 1 OF 2, CHAPTERS 4 AND 4A, PG&E'S REQUESTED EXPENSES FOR DIRECT ASSESSMENTS

QUESTION 9

On page 4A-27, PG&E discusses its request to assess 67 miles of pipeline using ICDA. Please provide the following information regarding its request:

a. Is PG&E's definition of "HCA" different than provided under 49 CFR § 192? If not, please identify if PG&E is using § 192.5 or § 195.903 in determining the HCA. If PG&E's definition is different than provided in the CFR, please explain, including identification of the criteria used to categorize a pipeline as "HCA".

b. Please provide a breakdown of PG&E's pipeline by class, "HCA" and "Non-HCA" if the definition of "HCA" and "Non-HCA" pipeline is different than that used in the response to ORA-07 Question 3A (attached for reference).

c. Please provide the number of miles of HCA pipelines PG&E assessed using ICDA each year from 2009-2013, and the annual expenses, in base year and nominal dollars.

d. For each year from 2009-2013, please provide the number of gas receipts and low spots assessed in order to evaluate the HCA pipelines using ICDA and expenses incurred for each activity.

e. Please provide the average number of gas receipts and/or low spots that must be assessed in order to assess 1 mile of pipeline using ICDA, each year from 2009-2013.

ANSWER 9

a. PG&E's definition of "HCA" (High Consequence Area) is the same as that provided under 49 Code of Federal Regulations (CFR) § 192. PG&E uses method 2 for "HCA" determination from 49 CFR § 192.903. 49 CFR § 192.5 is defining Class Location and is not used by industry to determine HCA, other than when used in 49 CFR § 192.903 to establish method 1 HCAs.

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b. PG&E does not use a different "HCA" definition from what is defined in ORA_007-Q03a, and, therefore is not providing a breakdown of its pipeline.

c. For the number of miles of HCA pipelines PG&E has assessed using Internal Corrosion Direct Assessment (ICDA) for years 2009 through 2013, please see the table below.

	Miles Assessed by Year				
Program	2009	2010	2011	2012	2013
ICDA	0	0	2	105	82

For the annual expenses of the ICDA program for years 2009 through 2013 in base year and nominal dollars, please see attachment GTS-RateCase2015_DR_ORA_070-Q09Atch01.

d. Per PG&E's Risk Management Procedure (RMP)-10, one of the locations assessed with ICDA per pipeline segment must be a low point. Low points can be sags, drips, valves, manifolds, dead-legs, and traps. Based on this information, the table below assumes that the number of low points assessed is correlated to the number of past ICDA projects performed. The approximate number of low points that have undergone direct examination from 2009-2013 are listed below along with the number of gas receipt points included in the ICDA process.

	ICDA Approximate Low Spots and Gas Receipts Assessed (2009-2013)				
Year	2009	2010	2011	2012	2013
Low Spots Assessed	0[1]	0	4	28	23
Gas Receipts Assessed	0[1]	0	1	6	4

[1]Note: In 2009 and 2010, there were no ICDA projects because no HCA assessments with the internal corrosion threat were due.

e. The ICDA process requires assessment of gas receipts and low spots for many miles leading into the HCA miles being assessed and, therefore, the number of gas receipts and/or low spots that must be assessed per mile varies greatly due to the variations in elevation profiles of each pipeline. Due to this variation, PG&E points out that the averages per mile will vary greatly. With that said, PG&E has established that the average number of gas receipts and/or low spots assessed per mile is approximately 0.35 inspection sites per mile and approximately 6 inspection sites per ICDA project (the latter being a more appropriate predictor of project costs).

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	ICDA Approximate Low Spots and Gas Receipts Assessed (2009-2013)					
Year	2009	2010	2011	2012	2013	2011-2013 Totals
Inspection Sites	0[1]	0[1]	5	34	27	66
Miles Assessed	0[1]	0[1]	1.6	104.5	82.3	188.4
Projects	0[1]	0[1]	1	6	4	11
2011-2013 Sites/Mile						**0.35**
2011-2013 Sites/Project						**6**

[1]Note: In 2009 and 2010, there were no ICDA projects because no HCA assessments with the internal corrosion threat were due.

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PACIFIC GAS AND ELECTRIC COMPANY
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Data Response

PG&E Data Request No.:	ORA_074-03		
PG&E File Name:	GTS-RateCase2015_DR_ORA_074-Q03		
Request Date:	June 13, 2014	Requester DR No.:	ORA-74
Date Sent:	June 25, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Bennie Barnes	Requester:	Dao Phan

SUBJECT: 2015 GAS TRANSMISSION AND STORAGE RATE CASE, PREPARED TESTIMONY, VOLUME 1 OF 2, CHAPTER 4 AND 4A, PG&E'S REQUESTED EXPENSES FOR DIRECT ASSESSMENTS

QUESTION 3

a. Which specific Risk Management Procedures is PG&E referring to on page 4A-27, lines 21-22? Please provide a copy of each procedure.

b. Explain the process PG&E used to select pipelines for assessment using the Risk Management Procedures; and

c. Identify the selection criteria PG&E used in determining the assessment method to be performed on pipelines (ECDA, ICDA, and/or SCCDA).

ANSWER 3

The attachment identified in this response has been marked CONFIDENTIAL and is submitted under Public Utilities Code Section 583 because it includes confidential employee information.

a. On page 4A-27, lines 21-22, PG&E is referring to its Risk Management Procedure, RMP-06, Revision 8. See attachment GTS-RateCase2015_DR_IndicatedProducers_002-Q085Atch03CONF of PG&E's response to IndicatedProducers_002-Q085.

b. Following is a summary of the process that PG&E uses to select pipelines for assessment, making reference to the pertinent sections of RMP-06 for the steps involved:
   1) HCA Identification (Section 6.0),
   2) Threat Identification (Section 7.0),
   3) Risk Assessment (Section 8.0); and
   4) Baseline Assessment Plan and Integrity Assessments (Section 9.0).

c. Assessment method selection is explained in RMP-06, section 9.3, "Selection of Assessment Method(s)".

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Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	ORA_074-08		
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PG&E Witness:	Bennie Barnes	Requester:	Dao Phan

SUBJECT: 2015 GAS TRANSMISSION AND STORAGE RATE CASE, PREPARED TESTIMONY, VOLUME 1 OF 2, CHAPTER 4 AND 4A, PG&E'S REQUESTED EXPENSES FOR DIRECT ASSESSMENTS

QUESTION 8

In footnote 14 at the bottom of page 4A-31, PG&E states, "Assuming a 7-year re- assessment cycle, the pipelines assessed in 2008-2010 will be due for reassessment in 2015-2017, or earlier for those pipes either operating above 50 percent Specified Minimum Yield Strength (SMYS) or those that were determined to require earlier reassessment based on previous inspection results." Please provide the following information regarding this statement:

a. Is PG&E on a 7-year re-assessment cycle? If not, what is PG&E's re-assessment cycle:

b. How did PG&E determine its re-assessment cycle? Provide a detailed explanation and provide a copy of all calculations and any and all documents relied on to determine its re-assessment cycle.

c. Please identify and provide the pipelines and segments assessed in 2008-2010, as referenced on page 4A-31, by pipeline number, segments, month/year of last inspection, and inspection method. Please provide this information in an Excel spreadsheet with active cells.

    i. Please highlight pipelines and segments assessed in 2008-2010 and were determined to require earlier reassessment.

        1. Of these pipelines and segments determined to require earlier reassessment, identify the lines and segments that have been assessed and the assessment dates.

d. Please identify and provide, in an Excel spreadsheet with active cells, the pipelines and segments assessed in 2008-2010 due for reassessment in 2015-2017.

    i. In this spreadsheet, please highlight the pipelines and segments PG&E proposes in testimony to assess using ECDA, ICDA, and SCCDA during the 2015-2017 timeframe.

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ANSWER 8

Attachment 01 to this response has been marked CONFIDENTIAL and is submitted pursuant to Section 583 of the Public Utilities Code because it includes confidential employee information.

a. In some situations, PG&E's re-assessment interval is 7 years. However, this is not always the case. PG&E's methodology for determining its reassessment intervals are explained in part b, below.

b. PG&E's process for determining reassessment intervals is described in its risk management procedure, RMP-06, section 11.1, "Assessment Intervals" on pages 29 through 30. For a copy of RMP-06, see GTS-RateCase2015_DR_IndicatedProducers_002-Q085Atch03CONF. Maximum reassessment intervals are established using American Society of Mechanical Engineers (ASME) B31.8S, Table 3. For External Corrosion Direct Assessment (ECDA), PG&E further adds a maximum 5 year interval for pipelines operating at or above 50% Specified Minimum Yield Strength (SMYS) based on the guidance by NACE International SP0502-2008. PG&E further notes that maximum reassessment intervals are not allowed to exceed the requirements of 49 Code of Federal Regulations (CFR) 192.939. Shorter reassessment intervals are governed by the processes spelled out in PG&E's risk management procedure, RMP-17, "Long Term Integrity Management Plan", section 6.3. The main purpose of this portion of RMP-17 is to confirm the maximum reassessment interval established by RMP-06. RMP-17 is provided as attachment GTS-RateCase2015_DR_ORA_074-Q08Atch01CONF.

c. For the pipelines and segments assessed from 2008 through 2010, please see attachments GTS-RateCase2015_DR_ORA_014-Q02Atch01 and GTS-RateCase2015_DR_ORA_014-Q02Atch02, PG&E and StanPac's 2012 integrity assessment plans respectively.

   For PG&E assessed segments, please see the tab titled "Table 2 HCA Assessment Plan" in attachment GTS-RateCase2015_DR_ORA_014-Q02Atch01. Please refer to Column B for the pipeline number, Column G for the date each segment was last assessed and Column K for the assessment method(s) applicable for each segment. PG&E has not determined that any segments assessed from 2008 to 2010 required an earlier reassessment. Some segments may be reassessed earlier based on reconfiguration of projects, however, this is in an effort to group pipeline segments in a logical manner.

   For StanPac assessed segments, please see the tab titled "Table 2 HCA Potential Threats" in attachment GTS-RateCase2015_DR_ORA_014-Q02Atch02. Please refer to Column B for the pipeline number, Column G for the date each segment was last assessed and Column K for the assessment method(s) applicable for each segment. PG&E has not determined that any segments assessed from 2008 to 2010 required an earlier reassessment. Some segments may be reassessed earlier based on reconfiguration of projects, however, this is in an effort to group pipeline segments in a logical manner.

   i. See response to part (c) above.

1. Not applicable. See response to part (c) above.

d. For the pipelines and segments assessed from 2008 through 2010, and due for reassessment between 2015 and 2017, please see attachments GTS-RateCase2015_DR_ORA_074-Q08Atch02 and GTS-RateCase2015_DR_ORA_074-Q08Atch03 for PG&E and StanPac respectively.

   i. Highlighted in each attachment are the segments PG&E proposes to assess using ECDA, Internal Corrosion Direct Assessment (ICDA) or Stress Corrosion Cracking Direct Assessment (SCCDA) during the 2015 Gas Transmission and Storage Rate Case period.

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PG&E Data Request No.:	ORA_074-09		
PG&E File Name:	GTS-RateCase2015_DR_ORA_074-Q09		
Request Date:	June 13, 2014	Requester DR No.:	ORA-74
Date Sent:	June 27, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Bennie Barnes	Requester:	Dao Phan

SUBJECT: 2015 GAS TRANSMISSION AND STORAGE RATE CASE, PREPARED TESTIMONY, VOLUME 1 OF 2, CHAPTER 4 AND 4A, PG&E'S REQUESTED EXPENSES FOR DIRECT ASSESSMENTS

QUESTION 9

Please identify the 355 miles of transmission lines PG&E proposes to assess using ECDA and provide the data collected on these lines such as: (1) installation date, (2) design & construction, (3) operation and maintenance history, (4) inspection dates, (5) condition of the pipe, (any corrosion identified?) (6) mitigation activities, and (7) recommended course of action. Please provide this data in an Excel spreadsheet with active cells.

ANSWER 9

For data regarding the segments of pipe within the proposed External Corrosion Direct Assessment (ECDA) program, please see GTS-RateCase2015_DR_ ORA_074-Q09Atch01. The data requested is shown in the spreadsheet as:

1. Installation date – Column F
2. Design & construction – Columns G through O
3. Operation & Maintenance history is done in accordance with 49 CFR 192 and General Order (GO) 112E
4. Inspection dates – inspections are scheduled for 2015-2017 – Column Q
5. The condition of the pipe related to ECDA is not known yet, as ECDA inspections have not yet occurred
6. Mitigation activities – no mitigation for ECDA has occurred yet because the ECDA has not yet occurred
7. The current recommended course of action of all based on the risk in Column P is to conduct ECDA in 2015-2017 for these approximately 355 miles

Please note that the attachment only has data representing the approximately 220 miles being reassessed during the 2015 Gas Transmission and Storage rate case years. The remainder of the proposed miles are composed of new High Consequence Area (HCA) miles resulting from the Transmission pipeline definition change. The total population of new transmission mileage will not be known until that analysis is completed in late 2014.

Those miles are then analyzed for new HCAs, which begin in 2015, with the final analysis completed in late 2015.

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Data Response

PG&E Data Request No.:	ORA_083-01		
PG&E File Name:	GTS-RateCase2015_DR_ORA_083-Q01		
Request Date:	June 24, 2014	Requester DR No.:	ORA-GT&S-83
Date Sent:	July 16, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Bennie Barnes	Requester:	Dao Phan/ Nathaniel Skinner

SUBJECT: 2015 GAS TRANSMISSION AND STORAGE RATE CASE, PREPARED TESTIMONY, VOLUME 1 OF 2, CHAPTER 4 AND 4A, PG&E'S REQUESTED EXPENSES FOR DIRECT ASSESSMENTS

QUESTION 1

For "Cost Estimate Bases," PG&E states: "The following numbers were used for the cost forecasts for 2015 through 2017. There [sic] were calculated from the actual costs of 2013 projects. The unit costs of above ground surveys and direct examination are the average of the actual costs."

a. Please provide a listing of all 2013 ECDA projects and identify whether PG&E started, was in the middle of, or completed the project in 2013.

b. Provide the calculations referenced in the statement above wherein PG&E states, "...calculated from the actual costs of 2013".

c. Identify the projects used in the calculations.

d. Identify the projects and project costs PG&E used to come up with the average cost referenced above for "above ground surveys" and for "direct examination." Please provide the calculations.

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ANSWER 1

a. For a listing of all 2013 External Corrosion Direct Assessment (ECDA) projects, please see the table below. An "x" in each column represents that the project phase was completed in 2013.

Project	Pre-Assessment	Above Ground Surveys	Direct Examination	Post-Assessment
21-2013	x	x	x	
191-2013	x	x	x	
137-2013	x	x	x	x
126-2013	x	x	x	
103-2013	x	x	x	x
124-2013	x	x	x	
197-2013	x	x	x	
181-2013	x	x	x	
301-2013	x	x	x	
210-2013	x	x	x	
220-2013	x	x	x	
116-2013	x	x	x	
119-2013	x	x	x	
123-2013	x	x	x	
121-2013	x	x	x	
402-2013	x	x	x	
173-2013	x	x	x	
50-2013	x	x	x	
132-2013	x	x	x	
142-2013	x	x	x	
300-2013	x	x	x	
2013Stations	x	x	x	
2013Casings	x	x	x	
2013 Water Crossings	x	x		

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b. Please note that there is a correction pending for the notes in the "Cost Estimate Basis." This correction will change note 1 to say, "The following numbers were used for the cost forecasts for 2015 through 2017. They were calculated from using the actual costs of 2013 projects through the end of July 2013, and forecasts for the remaining work to be done through the end of 2013. The unit costs of above ground surveys and direct examination are the average of the total costs." For the calculations used in forming the 2015 – 2017 forecasts please see the table below.

Description	Mile	Digs	Total Dig Costs	Total Survey Costs
021-2013	26.57	5	$ 522,126.13	$ 903,763.52
050-2013	3.00	3	$ 346,901.66	$ 157,045.66
103-2013	1.51	3	$ 321,264.63	$ 109,841.18
109-2013	7.15	3	$ 346,901.66	$ 288,521.23
116-2013	1.49	3	$ 346,901.66	$ 109,207.56
119-2013	3.16	4	$ 404,634.92	$ 162,114.60
121-2013	2.42	4	$ 398,004.36	$ 138,670.76
123-2013	1.50	3	$ 346,901.66	$ 109,524.37
124-2013	2.40	3	$ 363,506.73	$ 138,037.15
126-2013	0.43	2	$ 199,899.97	$ 75,625.85
132-2013	1.92	3	$ 346,901.66	$ 122,830.33
137-2013	1.09	3	$ 285,313.68	$ 96,535.22
142-2013	8.32	3	$ 346,901.66	$ 325,587.84
150-2013	0.04	3	$ 346,901.66	$ 63,270.32
173-2013	6.80	3	$ 346,901.66	$ 277,432.93
181-2013	16.16	3	$ 346,901.66	$ 573,965.78
187-2013	2.50	3	$ 346,901.66	$ 141,205.23
191-2013	13.12	3	$ 346,901.66	$ 477,655.96
197-2013	0.70	8	$ 792,628.75	$ 84,179.69
210-2013	1.25	3	$ 346,901.66	$ 101,604.16
220-2013	3.05	4	$ 355,635.05	$ 158,629.71
Nseg 300	9.08	3	$ 879,584.05	$ 349,665.29
Nseg 301	7.47	3	$ 346,901.66	$ 298,659.11
Nseg 402	3.51	3	$ 346,901.66	$ 173,202.90
2012 Effectiveness Digs	0.00	11	$ 1,047,799.55	$ 62,003.08
2013 Station DA	0.00	6	$ 609,738.37	$ 201,398.87
2013 Casings	0.00	6	$ 817,577.95	$ 62,003.08
2013 Water Crossings	0.00	3	$ 517,577.95	$ 62,003.08
Totals	**124.64**	**107**	**$ 12,371,915.28**	**$ 5,824,184.47**

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c. Please see the table in the response to (b).

d. Please see the table in the response to (b).

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PG&E Data Request No.:	ORA_083-06		
PG&E File Name:	GTS-RateCase2015_DR_ORA_083-Q06		
Request Date:	June 24, 2014	Requester DR No.:	ORA-GT&S-83
Date Sent:	July 17, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Bennie Barnes	Requester:	Dao Phan/ Nathaniel Skinner

SUBJECT: 2015 GAS TRANSMISSION AND STORAGE RATE CASE, PREPARED TESTIMONY, VOLUME 1 OF 2, CHAPTER 4 AND 4A, PG&E'S REQUESTED EXPENSES FOR DIRECT ASSESSMENTS

QUESTION 6

Please explain the term "New HCA" and provide a copy of the supporting calculations and any and all documents used to determine the "New HCA" mileage in PG&E's 2015-2017 forecast.

ANSWER 6

As stated in PG&E's response to TURN_011-Q12, the new High Consequence Areas (HCAs) that are identified in the workpapers supporting Chapter 4A on page WP 4A-17 are capturing those new HCAs that are estimated to exist as a result of the new transmission definition. It is estimated that approximately 133 of the 920 miles that meet the new transmission definition will require Direct Assessment, which will be completed during the 2015 Gas Transmission and Storage Rate Case period.

PG&E based the "new HCA" as referenced on WP 4A-17 on the fact that approximately 15% of the pipe that PG&E currently operates as transmission, operating at less than 20% Specified Minimum Yield Strength (SMYS), is HCA and has threats that require Direct Assessment in compliance with 49 Code of Federal Regulations (CFR), Subpart O. A more detailed analysis is not available because the analysis of which portions of pipe meet the new definition is still underway and will not be complete until late 2014.

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PG&E Data Request No.:	ORA_083-07		
PG&E File Name:	GTS-RateCase2015_DR_ORA_083-Q07		
Request Date:	June 24, 2014	Requester DR No.:	ORA-GT&S-83
Date Sent:	July 18, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Bennie Barnes	Requester:	Dao Phan/ Nathaniel Skinner

SUBJECT: 2015 GAS TRANSMISSION AND STORAGE RATE CASE, PREPARED TESTIMONY, VOLUME 1 OF 2, CHAPTER 4 AND 4A, PG&E'S REQUESTED EXPENSES FOR DIRECT ASSESSMENTS

QUESTION 7

Provide a step by step walk-through and explain how the unit costs, mileage, projects, and estimated digs for 2015, as presented in PG&E's workpapers at WP 4A-18 result in the forecast of $24,859,493 on WP 4A-17.

ANSWER 7

Please note that a correction will be made to the External Corrosion Direct Assessment (ECDA) workpaper to include the Pre-Assessment costs that were inadvertently left out of the initial forecast. This response includes the added costs.

The annual forecasts for the ECDA Program consist of four phases as shown in the corrected workpapers pages WP 4A-17 to WP 4A-18 in GTS-RateCase2015_DR_ORA_083-Q7Atch01: 1) Pre-Assessment, 2) Above Ground Indirect Surveys, 3) Direct Examination and Non-Destructive Examination (NDE), and 4) Post-Assessment. In addition, this attachment includes corrections to the Cost Estimate Bases and unit cost assumption to clarify 2013 costs as noted in the response to ORA_083-Q1.

As shown in GTS-RateCase2015_DR_ORA_083-Q7Atch01, mileage to be assessed using ECDA has been divided into Existing High Consequence Area (HCA) and New HCA. These two groups of projects each contain the four phases of work previously cited. Each of the four phases contains a unit cost basis that leads to the forecast of work required in 2015. To calculate the 2015 forecast for Pre-Assessments, the forecasted number of 2015 Existing HCA projects and 2015 New HCA projects to be performed using ECDA are multiplied by the pre-assessment project cost of $80,000 per project. For additional information related to the post-assessment unit cost, please see the response to question 4 part b. To calculate the 2015 forecast for Above Ground Indirect Surveys, the forecasted 2015 HCA miles to be assessed (both Existing and New) are multiplied by the survey unit cost of $46,708.05 per mile. To calculate the 2015 forecast for Direct Examination and NDE, the forecasted quantity of 2015

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Estimated Digs (both Existing and New HCA) are multiplied by the dig unit cost of $115,625.38 per dig. To calculate the 2015 forecast for Post-Assessments, the forecasted number of 2015 Existing HCA Projects and 2015 New HCA projects to be performed using ECDA are multiplied by the post- assessment project cost of $30,000 per project. For additional information related to the post-assessment unit cost, please see the response to ORA_083-Q04 part (c). The sum of the three phases of work for Existing HCA and New HCA equates to the 2015 forecast of $26,859,493.

The section below illustrates the math behind the forecast:

<u>2015 Pre-Assessments</u>:

15 Projects for Existing HCA x $80,000 per project = $1,200,000

10 Projects for New HCA x $80,000 per project = $800,000

Sum of 2015 Post-Assessments = $2,000,000

<u>2015 Above Ground Indirect Surveys</u>:

51 Miles of Existing HCA x $46,728 per mile= $2,383,128

44.3 Miles of New HCA x $46,728 per mile = $2,070,050

Sum of 2015 Above Ground Surveys = $4,453,178

<u>2015 Direct Examination and NDE</u>:

105 Estimated Digs for Existing HCA x $115,625 per dig = $12,140,665

65 Estimated Digs for New HCA x $115,625 per dig = $7,515,650

Sum of 2015 Direct Examination and NDE = $19,656,315

<u>2015 Post-Assessments</u>:

15 Projects for Existing HCA x $30,000 per project = $450,000

10 Projects for New HCA x $30,000 per project = $300,000

Sum of 2015 Post-Assessments = $750,000

Sum of All 4 Phases:

$2,000,000 from Pre-Assessments

$4,453,178 from Above Ground Surveys

$19,656,315 from Direct Examination

$750,000 from Post-Assessments

$26,859,493 – 2015 ECDA Program Forecast

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	2015		2016		2017	
Description	**Existing HCA**	**New HCA**	**Existing HCA**	**New HCA**	**Existing HCA**	**New HCA**
Pre-assessment of next year projects, Engineering, etc	$1,200,000	$800,000	$1,440,000	$800,000	$2,000,000	$800,000
Above ground surveys	$2,383,128	$2,070,050	$3,037,320	$2,070,050	$4,953,168	$2,070,050
Direct examination and NDE	$12,140,665	$7,515,650	$14,568,798	$7,515,650	$20,234,442	$7,515,650
Post-assessement of previous year projects	$450,000	$300,000	$540,000	$300,000	$750,000	$300,000
Subtotal Forecast	**$16,173,793**	**$10,685,700**	**$19,586,118**	**$10,685,700**	**$27,937,610**	**$10,685,700**
Total Forecast by Year (non-escalated):	**$26,859,493**		**$30,271,818**		**$38,623,310**	
Escalation factor	**1.055**		**1.08**		**1.106**	
Total Forecast by Year (escalated):	**$28,336,765**		**$32,693,563**		**$42,717,380**	

Grand Total Forecast (non-escalated): **$95,754,621**

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HPC ECDA Cost Calculator ~~(ORIG)~~ Revised

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Year	Mileage	Projects	Estimated Digs	Pre - assessment	Estimated Survey Cost	Estimated Digs Cost	Post-assessement	Cost forecast	Escalatation Factor	Escalated Forecast
2014	139.53	21	154	$1,680,000	$6,519,958	$17,806,309	$630,000	$23,574,297	N/A	N/A
2015	51	15	105	$1,200,000	$2,383,128	$12,140,665	$450,000	$3,583,233	1.055	$3,780,311
2015 New HCA	44.3	10	65	$800,000	$2,070,050	$7,515,650	$300,000	$2,870,115	1.055	$3,027,972
2016	65	18	126	$1,440,000	$3,037,320	$14,568,798	$540,000	$4,477,446	1.080	$4,835,642
2016 New HCA	44.3	10	65	$800,000	$2,070,050	$7,515,650	$300,000	$2,870,115	1.080	$3,099,725
2017	106	25	175	$2,000,000	$4,953,168	$20,234,442	$750,000	$6,953,343	1.106	$7,690,397
2017 New HCA	44.3	10	65	$800,000	$2,070,050	$7,515,650	$300,000	$2,870,115	1.106	$3,174,348

Cost Estimate Bases

1. The following numbers were used for the cost forecasts for 2015 through 2017. There were calculated from the actual costs of 2013 projects. The unit costs of above ground surveys and direct examinaiton are the average of the actual costs.

2. Above ground survey costs include engineering, permiting, estimating and other work related to indirect inspection survey.

3. Direct examination costs include engineering, permiting, estimating, excavating and other work related to bell hole inspection, with normal conditions.

4. 49 CFR Part 192.925

Pre-assessment	**$80,000**	$/project, estimated, including engineering for next year preassessment, permitting, estimating etc.
Above ground survey	**$46,728**	$/mile, see unit cost calculation table below
Direct examination cost	**$115,625**	$/dig, see unit cost calculation table below
Post-assessement	**$30,000**	$/project, estimated, including post-assessment for previous year projects and project management

Assumptions

1. The average unit cost for above ground surveys per mile and direct examinations per location, and the excavation numbers of each project/each year will be determined by review of historical data from prior projects. For estimating purposes, planning, permitting, materials, project management, support work, and construction labor will all be averaged into the unit cost estimate.

2. Unit cost calculation based on 2013 costs

Item	Total Costs	Work	Unit Cost
Digs	$12,371,915.28	107 digs	$115,625.38 /dig
Survey	$5,824,184.47	124.64 miles	$46,728.05 /mile

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	2015		2016		2017	
Description	Existing HCA	New HCA	Existing HCA	New HCA	Existing HCA	New HCA
Pre-assessment of next year projects, Engineering, etc	$1,200,000	$800,000	$1,440,000	$800,000	$2,000,000	$800,000
Above ground surveys	$2,383,128	$2,070,050	$3,037,320	$2,070,050	$4,953,168	$2,070,050
Direct examination and NDE	$12,140,665	$7,515,650	$14,568,798	$7,515,650	$20,234,442	$7,515,650
Post-assesement of previous year projects	$450,000	$300,000	$540,000	$300,000	$750,000	$300,000
Subtotal Forecast	**$14,973,793**	**$9,885,700**	**$18,146,118**	**$9,885,700**	**$25,937,610**	**$9,885,700**
Total Forecast by Year (non-escalated):	**$24,859,493**		**$28,031,818**		**$35,823,310**	
Escalation factor	**1.055**		**1.08**		**1.106**	
Total Forecast by Year (escalated):	**$26,226,765**		**$30,274,363**		**$39,620,581**	

Grand Total Forecast (non-escalated):	**$88,714,621**
Grand Total Forecast (escalated):	**$96,121,709**

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Year	Mileage	Projects	Estimated Digs	Pre - assessment	Estimated Survey Cost	Estimated Digs Cost	Post-assessement	Cost forecast
~~2014~~	~~139.53~~	~~24~~	~~154~~	~~$1,680,000~~	~~$6,519,958~~	~~$17,806,309~~	~~$636,000~~	~~########~~
2015	51	15	105	$1,200,000	$2,383,128	$12,140,665	$450,000	~~233~~ $16,1
2015 New HCA	44.3	10	65	$800,000	$2,070,050	$7,515,650	$300,000	~~115~~ $10,6
2016	65	18	126	$1,440,000	$3,037,320	$14,568,798	$540,000	~~446~~ $19,5
2016 New HCA	44.3	10	65	$800,000	$2,070,050	$7,515,650	$300,000	~~115~~ $10,6
2017	106	25	175	$2,000,000	$4,953,168	$20,234,442	$750,000	~~343~~ $27,9
2017 New HCA	44.3	10	65	$800,000	$2,070,050	$7,515,650	$300,000	~~115~~ $10,6

Cost Estimate Bases

1. The following numbers were used for the cost forecasts for 2015 through 2017. ~~There were calculated from the actual costs of 2013 projects.~~ They were calculated from using the actual costs of 2013 projects through the end of July 2013, and forecasts for the remaining work to be done through the end of 2013. The unit costs of above ground surveys and direct examination are the average of the total costs.

2. Above ground survey costs include engineering, permiting, estimating and other work related to indirect inspection survey.

3. Direct examination costs include engineering, permiting, estimating, excavating and other work related to bell hole inspection, with normal conditions.

4. 49 CFR Part 192.925

Pre-assessment	**$80,000**	$/project, estimated, including engineering for next year preassessment, permitting, estimating etc.
Above ground survey	**$46,728**	$/mile, see unit cost calculation table below
Direct examination cost	**$115,625**	$/dig, see unit cost calculation table below
Post-assessement	**$30,000**	$/project, estimated, including post-assessment for previous year projects and project management

Assumptions

1. The average unit cost for above ground surveys per mile and direct examinations per location, and the excavation numbers of each project/each year will be determined by review of historical data from prior projects. For estimating purposes, planning, permitting, materials, project management, support work, and construction labor will all be averaged into the unit cost estimate.

2. ~~Unit cost calculation based on 2013 costs~~ Unit cost calculation based on 2013 actual costs of 2013 projects through the end of July 2013, and forecasts for the remaining costs of 2013.

Item	Total Costs	Work	Unit Cost
Digs	$12,371,915.28	107 digs	$115,625.38 /dig
Survey	$5,824,184.47	124.64 miles	$46,728.05 /mile

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	2015		2016		2017	
Description	Existing HCA	New HCA	Existing HCA	New HCA	Existing HCA	New HCA
Pre-assessment of next year projects, Engineering, etc	$1,200,000	$800,000	$1,440,000	$800,000	$2,000,000	$800,000
Above ground surveys	$2,383,128	$2,070,050	$3,037,320	$2,070,050	$4,953,168	$2,070,050
Direct examination and NDE	$12,140,665	$7,515,650	$14,568,798	$7,515,650	$20,234,442	$7,515,650
Post-assessement of previous year projects	$450,000	$300,000	$540,000	$300,000	$750,000	$300,000
Subtotal Forecast	~~$14,973,793~~ $16,173,793	~~$9,885,700~~ $10,685,700	~~$18,146,118~~ $19,586,118	~~$9,885,700~~ $10,685,700	~~$25,937,610~~ $27,937,610	~~$9,885,700~~ $10,685,700
Total Forecast by Year (non-escalated):	~~$24,859,493~~ $26,859,493		~~$28,031,818~~ $30,271,818		~~$35,823,310~~ $38,623,310	
Escalation factor	1.055		1.08		1.106	
Total Forecast by Year (escalated):	~~$26,226,765~~ $28,336,765		~~$30,274,363~~ $32,693,563		~~$39,620,581~~ $42,717,381	

Grand Total Forecast (non-escalated): ~~$88,714,621~~ $95,754,621

Grand Total Forecast (escalated): ~~$96,121,709~~ $103,747,709

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